

October 19, 2016

The Honorable Heather McTeer Toney
Regional Administrator
EPA Region 4
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, GA 30303-8960

RE: Draft National Pollutant Discharge Elimination System (NPDES) general permit for the Outer Continental Shelf (OCS) of the Gulf of Mexico (General Permit No. GEG460000); Public Notice 16AL00001

Dear Administrator Toney:

As the national trade association for the oilfield service, supply, and manufacturing sector, the Petroleum Equipment and Services Association (PESA) appreciates the opportunity to provide comments on the draft National Pollutant Discharge Elimination System (NPDES) general permit for the Outer Continental Shelf (OCS) of the Gulf of Mexico (General Permit No. GEG460000) for discharges in the Offshore Subcategory of the Oil and Gas Extraction Point Source Category.

PESA represents approximately 200 companies that develop and provide the services, technology, equipment, chemicals, and expertise necessary to safely and efficiently explore for and produce oil and natural gas. Many of these companies are involved as contracted vendors to exploration and production companies and/or drilling contractors working in the Gulf of Mexico, including Region 4.

PESA members are committed to conducting their work in a safe and environmentally responsible manner. The comments provided to EPA reflect the perspective of subject matter experts from numerous PESA member companies and are intended to ensure that the permit meets the shared goals of EPA and industry: Safe and environmentally responsible operations.

Should you have any questions, please do not hesitate to contact me directly.

Sincerely,

/s/

Ryan S. Bowley
Vice President, Operations & External Affairs

Notification Requirements (Existing Sources and New Sources) - Part I., A., 4., u.

Current Region 4 Proposed Permit Language:

“u. Information on the specific chemical composition of any additives currently being used or proposed for use in well treatment, completion or workover operations or as biocides for sump/drain systems. If the information on the additive is not known at the time of the submittal of this NOI, operators shall include the information in a report that shall be submitted on to EPA Region 4 on September 30th of each year. Aside from submitting this information with the NOI, this information is also required to be recorded and retained on site for no less than five years from the issuance date of the permit. See Part I.6.a.iii.”

PESA Revised Permit Wording/Clarification:

u. Information on the identity, as listed on the applicable SDS, and concentration of each chemical constituent, intentionally added to the well treatment, completion or work over fluid of currently being used and discharged or proposed for use and discharge in well treatment, completion or workover operations. If the information on the additive is not known at the time of the submittal of this NOI, operators shall include the information in a report that shall be submitted on to EPA Region 4 on September 30th of each year or with the alternative study report of Part I.B.6.b. If an operator participates in the alternative study, then annual information submittal is not required. Operators may submit this information marked as “Confidential Business Information” or other suitable form of notice or may have service providers independently submit this information marked as such if necessary. The information so marked shall be treated as information subject to a business confidentiality claim pursuant to 40 CFR Part 2. Aside from submitting this information with the NOI, this information is also required to be recorded and retained on site for no less than five years from the issuance date of the permit, except for Confidential Business Information which may be maintained securely offsite by the operator or relevant service provider, for no less than five years from the issuance date of the permit. See Part I.B.6.a.iii.

Justification and Supporting Documentation:

PESA requests that any requirements for disclosure of treatment, completion and workover fluid compositional information be clarified as to the extent of disclosure required. The proposed revision reflects a requirement for disclosure of composition as described on the SDS for relevant additives. Additionally, PESA requests that the disclosure requirement allows for the use of a “systems-style” disclosure of the chemical composition of all additives in a fluid (or fluids, in the case of multiple disclosed applications), consistent with the approach that has been adopted for use in certain jurisdictions and by FracFocus. System-style disclosure would satisfy the objectives of the permit revision while potentially reducing the necessity for companies to make confidential business information claims on such disclosures.

System-style disclosure lists all known chemical constituents in a fluid (or fluids, in the case of multiple disclosed applications), but decouples those constituents from their parent additives, thus improving protection of the proprietary chemistry used in hydraulic fracturing while promoting greater disclosure. At the same time, reverse engineering of product formulas may still be possible with the use of a systems-style disclosure. A chemist or chemical engineer who knows the industry and the well treatment process will be familiar with the types of chemicals (usually a limited number) that have typically been used in a

particular type of additive. The chemist or chemical engineer will be able to determine in most cases what role each chemical in the list plays in the overall product formulation and would be able to identify the ingredients included in the proprietary product. The chemist or chemical engineer will also be able to determine the general proportions that each ingredient would constitute of the whole (again with assistance from information on the product's Safety Data Sheet which include additional concentration information for various hazardous ingredients). Therefore, in order to protect the substantial investment of time and resources in developing proprietary products, it is critical that operators and service companies have the ability to protect proprietary information as Confidential Business Information even when using a systems-style approach.

Also, PESA requests that service providers be permitted to disclose trade secret/CBI information directly to EPA rather than requiring disclosure through the operators. Such independent disclosure is necessary in order to protect the substantial investment of time and resources that service providers make in developing proprietary products. Chemical additives play a critical role in the safety, efficiency and productivity of offshore wells, and access to newly-developed, ever-improving chemicals—be they “greener,” more efficient or more effective—is in turn critical to continued improvements in offshore operations.

Drilling Fluids Limitations – Part I., B., 1., b.

Current Region 4 Proposed Permit Language:

“...Analyses for cadmium shall be conducted by EPA Methods 200.7, 200.8 or EPA Method 3050 B followed by 6010 B or 6020A (EPA SW 846), or more recently approved EPA methods, and results shall be expressed in mg/kg (dry weight) of stock barite. Analysis for mercury shall be conducted using EPA Method 245.7 or EPA method 7471 A (EPA SW 846), or most recently approved EPA methods, and expressed as mg/kg (dry weight) of stock barite...”

PESA Revised Permit Wording/Clarification:

“...Analysis for cadmium shall be conducted using EPA methods 200.7, 200.8, or EPA method 3050 B followed by 6010B or 6020, or more recently approved and validated methods and the results expressed as mg/kg (dry weight) of stock barite. Analyses for mercury shall be conducted using EPA method 245.5, method 7471 B, or more recently approved and validated methods and the results expressed in mg/kg (dry weight) of stock barite.”

Justification and Supporting Documentation:

Method 245.7 proposed by EPA Region 4 is designed to measure mercury in water and is not designed to measure mercury in solids (barite). Therefore, the reference to 245.7 should be changed to method 245.5 which is designed for solids. The parallel method to 245.5 is Method 7471A which has been updated in 2007 to Method 7471B. (See documentation in Appendix Item 1). Therefore, the recommendation is to change 7471A to 7471B.

The information in the Appendix shows a split sample analysis from a lab with significant experience using Method 7471B. Previous internal studies developed a dual control system to ensure matrix interference issues were addressed so that two very long term controls yielded one control with a long term average of 0.62 mg/kg (below) the limit and another long term control with a long term average of 2.2 mg/kg (above the limit).

Within these control limits the use of method 7473 was tested and the comparison was favorable. Then a sample with much higher mercury of 7.5 mg/kg was tested using Method 245.5. The split sample results

using method 7473 produced much lower results using two different instruments (average results 0.74mg/kg, and 0.88 mg/kg). These results, included in the Appendix, indicate that method 7473 requires additional investigation and validation for mercury analysis to avoid potential false negative results on some barite sources that have higher concentrations of mercury. Maintaining the proposed language in the permit ensures that other test methods may continue to be used.

There is some preliminary information available in the Appendix to indicate that Method 245.7 may be appropriate when combined with the extraction method 3051A. (See documentation in Appendix Item 1)

There is a potential concern that EPA method 7473 may not extract mercury from the barite matrix. This is noted as a possibility in the method scope and application. Since this method is not specifically listed by Region 4 it could be considered as an alternative “newer” method if the current Region 6 language “...or more recently approved methods...” is adopted (See documentation in Appendix Item 1). Because it may not recover as much of the mercury out of the barite matrix as does methods 245.5 and 7471B it needs additional validation and approval prior to use as an approved method in the permit.

Because the permit limitation for mercury and cadmium is on barite, a specific solid matrix, prior to any modifications the permit language the operator in cooperation with the Agency should validate and approve any alternative method.

Drilling Fluids Inventory Documentation – Part I., B., 1., c., 1.

Current Region 4 Proposed Permit Language:

“i. Drilling Fluids Inventory. The permittee shall maintain a precise chemical usage record of all constituents and their total volume and mass added for each well. Information shall be recorded and retained for the term of the permit.”

PESA Revised Permit Wording/Clarification:

i. Drilling Fluids Inventory. The permittee shall maintain a precise chemical usage record of all products and their total volume and mass added for each well. Information shall be recorded and retained for the term of the permit.

Justification and Supporting Documentation:

Drilling Fluid Chemical inventory for drilling operations is currently maintained using product names and quantities of products added to the drilling fluid. Use of the term products will maintain clarity and conformity of the records maintained by Drilling Fluid Specialist and Service company records provided to the operators for commercial, technical and permit compliance purposes.

Well Treatment, Completion and Workover Fluids, Priority Pollutants - Part I., B., 6., a., iii. & b.”

Current Region 4 Proposed Permit Language:

“iii. Priority Pollutants. For well treatment fluids, completion fluids, and workover fluids, the discharge of priority pollutants is prohibited except in trace amounts. If multiple fluids are mixed, each fluid must be checked for priority pollutants. “Trace amounts” shall mean the amount equal to or less than the most sensitive method detection limit listed in 40 C.F.R. Part 136 for the applicable parameter. Vendor certification indicating the fluids contain no priority pollutants is acceptable for meeting this requirement.

Information on the specific chemical composition of any additives containing priority pollutants shall be recorded and submitted as part of the NOI (see part I.4.u) Any updated information regarding chemical composition of new formulations that contain priority pollutants and will be used shall be submitted to EPA Region 4 annually no later than September 30th. Operators may submit this information marked as “Confidential Business Information,” if necessary. Copies of these records should also be kept on the rig while the rig is on the permitted location and thereafter at the permittee’s shore base or office. These record retention requirements supersede those found in Part II.C.5. of this permit.

Note: If materials added downhole as well treatment, completion, or workover fluids contain no priority pollutants as determined by using analytical methods in 40 C.F.R. Part 136, the discharge is assumed not to contain priority pollutants.”

PESA Revised Permit Wording/Clarification:

Priority Pollutants. For well treatment fluids, completion fluids, and workover fluids, the discharge of priority pollutants is prohibited except in trace amounts. Information on the specific chemical composition of any additives containing priority pollutants shall be recorded. [Note: If materials added downhole as well treatment, completion, or workover fluids contain no priority pollutants, the discharge is assumed not to contain priority pollutants except possibly in trace amounts.]

Fluids Commingled with Produced Water. When fluids are commingled and discharged with produced water, the discharges are considered produced water and the operator may report “no discharge” for monitoring and reporting purposes.

Note: this is the same as current language in the Region 6 NPDES Permit.

Justification and Supporting Documentation:

During the development of the 1993 amendments to the Oil and Gas Extraction Effluent Guidelines and Standards (40 CFR Part 435), EPA researched and developed a significant amount of documentation reflecting industry practices and the materials used in the offshore drilling, well treatment, completion, and workover process. This work was recorded in the “Development Document for Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category” (January 1993, EPA 821-R-93-003, “Development Document”). Selected excerpts from that document are provided in the Appendix to these comments.

In the Development Document, EPA noted that Completion Fluids, Workover Fluids and Well Treatment Fluids were minor discharges. These fluids are not anticipated to contain priority pollutants other than in trace amounts. Recognizing that Zinc Bromide Brines used in some high density requirements for completion fluids, Region 6’s NPDES permitting activity has appropriately focused attention on preventing the discharge of Zinc Bromide completion fluids. Other trace amounts of priority pollutants in low volume discharges were considered by the Agency in the development of technology-based standards.

It was determined that downhole sources are the most likely source of priority pollutants; therefore, there was no need to place specific controls in Completion Fluids, Workover Fluids and Well Treatment Fluids beyond the controls that applied to the waste streams in which the used completion, workover, and/or well treatment fluids could be present after use downhole. The BAT/BCT requirements were placed on these discharges in consideration that likely contaminants would be the same as those in produced water. EPA appropriately focused attention on oil and grease which is an appropriate surrogate for priority pollutants likely to come from downhole sources.

Since this Effluent Limitation Guidelines Review in the late 1980s and early 1990s, the technical basis for the agency's determination remains sound. Therefore, the existing BAT/BCT limits continue to be appropriately focused on downhole contaminants in the form of oil and grease and not on the fluids used to service the well. This approach in regards to limits should be carried over into Region 4's final NPDES Permit while also incorporating the "system-style" disclosure as requested by PESA and other industry groups.

In addition to ensuring that focus continues to be placed on the most likely source of priority pollutants, it is important to consider the broader impact of the approach contained in the proposed permit. The extremely low levels of contamination triggered under proposed permit will cause companies operating in Region 4 to stop reuse of these frequently expensive fluids and instead haul them back to shore for treatment even when no oil or grease are present. Not only will this result in increased cost to industry, but also in increased fuel and associated emissions to haul brine fluids back to shore for treatment.

PESA members have noted that due to modern analytical techniques the most sensitive detection limit for zinc is 0.5 parts per billion (Appendix Item 3). If the 0.5 ppb discharge limit is applied to naturally occurring seawater, then unaltered seawater would not meet the discharge limit. (Appendix Item 4) This type of unobtainable regulatory control is not justified for a low volume discharge. Therefore, in order to prevent non-water quality impacts associated with discharge prohibitions, PESA requests that Region 4 reconsider its language in this part of the permit.

Well Treatment, Completion and Workover Fluids, Monitoring Requirements, Industry Wide Study Alternative - Part I.B.6. a. iv. to 6. c.

Current Region 4 Proposed Permit Language:

"iv. Chronic Whole Effluent Toxicity for Well Treatment, Completion or Workover fluids– Permittees with discharges of well treatment fluids, completion or workover lasting four or more consecutive days must monitor and report the No Observable Effect Concentration (NOEC) relative to the predicted effluent concentration at the edge of a 100-meter mixing zone. Predicted effluent concentrations, referred to as critical dilutions, are presented in Tables 3 and 4 of Appendix B for a range of discharge rates and pipe diameters.

Permittees discharging well treatment wastewater at conditions other than those covered in Tables 3 and 4 of Appendix A (e.g., at a rate greater flows, pipe diameters, or discharge densities) shall determine the critical dilution using the appropriate CORMIX model with the input parameters shown below. Permittees shall retain the model runs as part of the NPDES records. The critical dilution shall be determined using the CORMIX model using the highest daily average discharge rate for the three days prior to the day in which the test sample is collected, the discharge pipe diameter, the measured discharge density, and the depth difference between the discharge pipe and the sea bottom.

Input Parameters:

Density Gradient = 0.163 kg/m³/m

Ambient seawater density = 1023.0 kg/m³

Well Treatment wastewater density = 1030.0 – 1680.0 kg/m³

Completion and workover fluids = 1030.0 – 1680.0 kg/m³

Current speed = 5 cm/sec (<200 m water depth); 15 cm/sec (>200 m water depth)

The NOEC shall be calculated by conducting 7-day chronic toxicity tests in accordance with methods published in Short Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Water to Marine and Estuarine Organisms (EPA/821-R-02-014), or most current edition.

The results for both species shall be reported on the DMR. See Part V.A.15.a of this permit for Whole Effluent Toxicity Testing Requirements. Samples must be taken at the nearest accessible location prior to discharge. All modeling runs shall be retained by the permittee as part of its NPDES records.

v). Acute Whole Effluent Toxicity Testing for Well Treatment, Completion or Workover Fluids -The following Acute Whole Effluent Testing requirements apply to discharges of well treatment fluids that last less than 4 days. Permittees must monitor and report the acute critical dilution (ACD) at the edge of a 100 meter mixing zone. The ACD is defined as 1.0 times the LC50. The ACD and the predicted effluent concentration at the edge of a 100 meter mixing zone must be reported on the DMR. Predicted effluent concentrations, referred to as “critical dilutions,” are presented in Tables 3 and 4 of Appendix A for a range of discharge rates and pipe diameters. Critical dilution shall be determined using Tables 3 and 4 of this permit based on the most recent discharge rate, discharge pipe diameter, and water depth between the discharge pipe and the ocean bottom. LC50 shall be calculated by conducting 48-hour, non static renewal, toxicity tests once per discharge using *Mysidopsis bahia* and *Menidia beryllina* (Inland silverside minnow). Additional acute toxicity testing requirements are contained in Part V.15.b of this permit.

Permittees discharging well treatment wastewater at conditions other than those covered in Tables 3 and 4 of Appendix A (e.g., at a rate greater flows, pipe diameters, or discharge densities) shall determine the critical dilution using the appropriate CORMIX model with the input parameters shown below. Permittees shall retain the model runs as part of the NPDES records. The critical dilution shall be determined using the CORMIX model using the highest daily average discharge rate for the three days prior to the day in which the test sample is collected, the discharge pipe diameter, the measured discharge density, and the depth difference between the discharge pipe and the sea bottom.

Input Parameters:

Density Gradient = 0.163 kg/m³/m

Ambient seawater density = 1023.0 kg/m³

Well Treatment wastewater density = 1030.0 – 1680.0 kg/m³

Completion and workover fluids = 1030.0 – 1680.0 kg/m³

Current speed = 5 cm/sec (<200 m water depth); 15 cm/sec (>200 m water depth) Permittees shall retain the model runs as part of the NPDES records.

Samples for the acute WET tests shall be obtained at the nearest accessible point after final treatment and prior to discharge to surface waters.

b. Monitoring Requirements

Volume. The highest daily total discharge and the 3-month average discharge must be estimated and reported on the DMR in barrels per month.

Well Treatment Completion and Workover Reporting Requirements.

Operators of leases where well treatment, completion, or workover fluids are discharged shall collect and report the information listed below. This information shall be reported with the discharged monitoring report for the quarter in which the discharge is made. If discharges commence in one quarter and cease in the following quarter, reporting should be done in the later quarter.

For each well in which operations are conducted that result in the discharge of well treatment, completion, or workover fluids the following shall be reported with the discharge monitoring report for the quarter in which the activity is done:

- Lease and block number

- API well number
- Type of well treatment or workover operation conducted
- Date of discharge
- Time discharge commenced
- Duration of discharge
- Volume of well treatment
- Volume of completion or workover fluids used
- The common names and chemical parameters for all additives to the fluids
- The volume of each additive
- Concentration of all additives in the well treatment
- Concentration of all additives in the completion, or workover fluid
- Results of Whole Effluent Toxicity (WET) tests for well treatment fluids discharged separately from the produced water discharge. Additional toxicity testing requirements are contained in Part V.15.b of this permit.

Information collected for this reporting requirement shall be submitted as an attachment to the DMR or in an alternative format requested by the operator and approved by EPA Region 4.

Industry-Wide Study Alternative

Alternatively, operators who discharge well treatment completion and/or workover fluids may participate in an EPA-approved industry-wide study as an alternative to conducting monitoring of the fluids characteristic and reporting information on the associated operations. That study would, at a minimum, provide a characterization of well treatment, completion, and workover fluids used in a representative number of active wells of varying depths (shallow, medium depth and deep depths). In addition, an approved industry-wide study would be expected to provide greater detail on the characteristics of the resulting discharges, including their chemical composition and the variability of the chemical composition and toxicity. The study area should include a statistically valid number of samples of wells located in the Eastern Gulf of Mexico (GOM) and may include the Western and Central Areas of the GOM under the permitting jurisdiction of EPA Region 6, and operators may join the study after the start date. The study plan should also include interim dates/milestones.

A plan for an industry-wide study plan would be required to be submitted to EPA Region 4 for approval within six months after the effective date of this permit. If the Region approves an equivalent industry-wide well treatment fluids discharge monitoring study, the monitoring conducted under that study shall constitute compliance with these monitoring requirements for permittees who participate in such the industry-wide study. Once approved, the study plan will become an enforceable part of this permit. The study must commence within six months of EPA's approval. If the Region does not approve the study plan or if a permittee does not participate in the study, compliance with all the monitoring requirements for well, completion, and workover fluids is required (see above). The final study report must be submitted no later than three years from the effective date of this permit.

c. This discharge shall be considered "produced water" when commingled with produced water."

PESA Revised Permit Wording/Clarification:

EPA Region 4 will require development of appropriate toxicity testing strategies to determine a testing procedure that will address the following objectives for evaluation of these fluids. The options will be to:

- 1) Use EPA protocols already developed for produced water.
- 2) Develop alternative protocols as an individual operator.
- 3) Participate in an Industry Work Group to develop an appropriate method or methods meeting the following approach previously used to develop tests for synthetic-based mud cuttings.

Design parameters:

- 1) Maximum discriminatory power
- 2) Maximum repeatability of results
- 3) Practicality of implementation
- 4) Ranking of known test substances as expected
- 5) Ecological relevance
- 6) Government acceptance of the protocols

In a similar fashion, the following approach has been applied to the process of using the laboratory tests to qualify technologies for field application:

Development procedures:

- 1) Identify all of the available tests
- 2) Experimentally modify the tests to optimize them to meet the design objectives
- 3) Conduct screening tests to identify the strengths and weaknesses of the available test methods to meet the design objectives
- 4) Select a limited number of top contenders and further develop standardized protocols, maximize the positive qualities and minimize the negative qualities of the test
- 5) Select a top contender and propose the method
- 6) Validate the test methodology and develop a regulatory limit based on the test
- 7) Implement the test method in the field and correct any problems that affect the usefulness of the test.

Justification and Supporting Documentation:

The presumptive use of an off-the-shelf toxicity test designed for produced water may result in inappropriate and potentially counterproductive regulatory controls and technology applications. As such, PESA requests that EPA work with industry to develop an objective-based approach to toxicity evaluation that builds on the cooperative approach used during the development of tests for synthetic-based mud cuttings.

Examination of existing research highlights limitations in the proposed approach. For instance, it is well known that mysid shrimp have ion intolerance; therefore, any test for completion fluids and similar low solids/high salt solids free toxicity test are likely to primarily be driven by ion intolerance. Other targeted pollutants such as toxic pollutants or hydrocarbons, or surfactants other non-conventional pollutants would not be accurately monitored because the test would be blinded with ion toxicity. This issue was

summarized in SPE 37909 which discussed using Salinity-Toxicity Relationships in Toxicity Identification Evaluation (TIEs) for Produced Water. In this paper, the authors identified that Toxicity Identification Evaluations could be enhanced by the use of a Salinity Toxicity Relationship. The conclusions reached included:

- Traditional Toxicity Identification Evaluations (TIE) methods are ineffective in isolating toxicity due to common ions such as chloride, potassium, Calcium etc.
- Salinity Toxicity Relationship (STR) models can accurately predict ion related toxicity in effluents. When combined with mock effluent studies, STRs provide important evidence in TIE investigations.
- STRs can be used for many different effluents.

In addition, SPE 37909 and other SPE papers have further developed the concept and understanding of the role ions have in conventional effluent discharge testing. These papers include SPE 35845, SPE29730, SPE 26007. Consequently, the development of appropriate tests instead of off-the-shelf tests designed for other purposes is appropriate in this case for evaluation potential toxicants in completion fluids and other high salt, low solids fluids.

Additional consideration needs to focus on before use and after use and also recovered use of these fluids. In many cases expensive completion fluids are recovered and reused from well to well.

Test Procedures and Definitions, Test Procedures, Formation Oil – Part V., A., 9.

Current Region 4 Proposed Permit Language:

“a. Contamination of Non-Aqueous Based Drilling Fluids

The approved test method for permit compliance is Gas Chromatography/Mass Spectrometry (GC/MS) contained in Appendix 5 of 40 C.F.R. Part 435, subpart A (or most current EPA approved method). This test shall be performed prior to drilling. The GC/MS method reports results for the GC/MS test as a percentage crude contamination when calibrated for a specific crude oil. In order to define an applicable pass/fail limit to cover a variety of crude oils, the same crude oil used in calibration of the Reverse Phase Extraction (RPE) test shall be used to calibrate the GC/MS test results to a standardized ratio of the target ION Scan 105 (or most current EPA approved method). Based on the performance of a range of crude oils against the standardized ratio, a value will be selected as a pass/fail standard which will represent detection of crude oil.”

PESA Revised Permit Wording/Clarification:

a. Contamination of Non-Aqueous Based Drilling Fluids

The approved test method for permit compliance is Gas Chromatography/Mass Spectrometry (GC/MS) contained in Appendix 5 of 40 C.F.R. Part 435, subpart A (or most current EPA approved method). This test shall be performed prior to drilling. The GC/MS method reports results for the GC/MS test as a percentage crude contamination when calibrated for a specific crude oil. In order to define an applicable pass/fail limit to cover a variety of crude oils, the same crude oil used in calibration of the Reverse Phase Extraction (RPE) test shall be used to calibrate the GC/MS test results to a standardized ratio of the target ION Scan 105 (or most current EPA approved method). Based on the performance of a range of crude oils against the standardized ratio, the following modification will be used.

7.2.1 Crude Oil Reference- NIST 1582 or NIST 2779 Petroleum Crude Oil Standard Reference Material (U.S. Department of Commerce National Institute of Standards and Technology, NIST 2779 Petroleum Crude Oil Standard Reference Material (U.S. Department of Commerce National Institute of Standards and Technology)).

7.2.5 Crude oil/drilling fluid calibration standards -Prepare a 4-point crude oil/drilling fluid calibration at concentrations of 0% (no spike-clean drilling fluid), 0.5%, 1.0%, and 2.0% by volume according to the procedures outlined below using the Reference Crude Oils:

For NIST 1582

7.2.5.1 Label 4 vials with the following identification: Vial 1-0%Crude in NAF drilling fluid, Vial 2-0.5%Crude in NAF drilling fluid, Vial 3-1%Crude in NAF drilling fluid, and Vial 4-2%Crude in NAF drilling fluid.

7.2.5.2 Vial 1 will not be spiked with Reference Oil in order to retain a “0%” oil concentration, add 5 mL of clean NAF base fluid only.

7.2.5.3 Weigh 90.5 mg of NIST Crude Oil into Vial 2 and add 5 mL of clean NAF base fluid. This will be the 0.5% Crude equivalent in NAF mud standard.

7.2.5.4 Weigh 181 mg of NIST Crude Oil into Vial 3 and add 5 mL of clean NAF base fluid. This will be the 1.0% Crude equivalent in NAF mud standard.

7.2.5.5 Weigh 362 mg in NIST Crude Oil in Vial 4 and add 5 mL clean NAF base fluid. This will be the 2.0% Crude Equivalent in NAF mud standard

7.2.5.6 Thoroughly mix the contents of each of the 4 vial by shaking vigorously.

For NIST 2779

7.2.5.1 Label 4 vials with the following identification: Vial 1-0%Crude in NAF drilling fluid, Vial 2-0.5%Crude in NAF drilling fluid, Vial 3-1%Crude in NAF drilling fluid, and Vial 4-2%Crude in NAF drilling fluid.

7.2.5.2 Vial 1 will not be spiked with Reference Oil in order to retain a “0%” oil concentration, add 5 mL of clean NAF base fluid only.

7.2.5.3 Weigh 24.4 mg of NIST Crude Oil into Vial 2 and add 5 mL of clean NAF base fluid. This will be the 0.5% Crude equivalent in NAF mud standard.

7.2.5.4 Weigh 48.9 mg of NIST Crude Oil into Vial 3 and add 5 mL of clean NAF base fluid. This will be the 1.0% Crude equivalent in NAF mud standard.

7.2.5.5 Weigh 97.7 mg in NIST Crude Oil in Vial 4 and add 5 mL clean NAF base fluid. This will be the 2.0% Crude Equivalent in NAF mud standard

7.2.5.6 Thoroughly mix the contents of each of the 4 vial by shaking vigorously.

12.1 Total Area Integration Method

12.1.1 Using C8 to C13 TIC area, the TCB area in the clean NAF sample and the TIC linear regression curve, compute the oil equivalent concentration of the C8 to C13 retention time range in the clean NAF. Note: The actual TIC area of the C8 to C13 is equal to the C8 to 116 C13 area minus the area of the TCB.

12.1.2 Using the corresponding information for the authentic sample, compute the oil equivalent concentration of the C8 to C13 retention time range in the authentic sample.

12.1.3 Calculate the concentration (% oil) of oil in the sample by subtracting the oil equivalent concentration (% oil) found in the clean NAF from the oil equivalent concentration (% oil) found in the authentic sample. The C8 to C13 TIC area will not work well for clean NAF samples that contain measurable amounts of paraffins in the C8 to C13 range.

12.2 EIP Area Integration Method

12.2.1 Using the ratio of the 105 EIP area to the TCB m/z 91 EIP area in the clean NAF sample, and the appropriate EIP linear regression curve, compute the oil equivalent concentration of the in the clean NAF.

12.2.2 Using the corresponding information for the authentic sample, compute its oil equivalent concentration.

12.2.3. If the ratio of the of the 105 EIP area to the TCB m/z 91 EIP area for the authentic sample is greater than that for the 1% formation oil equivalent calibration standard, the sample is considered contaminated with formation oil.

Justification and Supporting Documentation:

In the development of the GC/MS procedure for formation oil testing in Synthetic Based Drilling Fluids, it was documented to the Agency that there is a wide variety of crude oils in the GOM. Use of a single crude oil reference and calibration of the crude oil to be representative promotes a consistent and accurate approach to a pass fail limit.

Standardization of Testing Methods & References

Permit Citation	Current Region 4 Proposed Permit Language:	PESA Revised Permit Wording/Clarification:
Part I Section 1.b.iii	“The analytical method is cited in 40 C.F.R. Part 435, Appendix 2 of subpart A, entitled, “Drilling Fluid Toxicity Test.”	The analytical method is cited in EPA Method 1619.
Part I Section 1.b.iv	“Monitoring shall be performed once per week using the Static Sheen Test method in accordance with the method provided in Part V.A.3, as published in 40 C.F.R Part 435, Appendix 1 of subpart A.”	Monitoring shall be performed once per week using the Static Sheen Test method in accordance with the method provided in Part V.A.3. (EPA Method 1617).
Part I Section 2.b.iii	“The analytical method is cited in 40 C.F.R. Part 435, Appendix 2 of subpart A, entitled, ‘Drilling Fluid Toxicity Test.’”	The analytical method is EPA Method 1619.
Part I Section 2.c.i.(1)	“Once prior to drilling using the gas chromatography/mass spectrometry (GC/MS) method specified in Appendix 5 of 40 C.F.R. Part 435, subpart A. Alternatively, the permittee may provide certification, as documented by the supplier(s) that the drilling fluid being used on the well contains no formation oil as determined using the	Once prior to drilling using the gas chromatography/mass spectrometry (GC/MS) EPA Method 1655. Alternatively, the permittee may provide certification, as documented by the supplier(s) that the drilling fluid being used on the well contains no formation oil as determined using the GC/MS EPA Method 1655.

	GC/MS method in Appendix 5 of 40 C.F.R. Part 435, subpart A.”	
Part I Section 2.c.i.(2)	“Once per week during drilling using the Reverse Phase Extraction (RPE) test method specified in Appendix 6 of 40 C.F.R. part 435, Subpart A.”	Once per week during drilling using the Reverse Phase Extraction (RPE) test method EPA Method 1670.
Part I Section 2.c.ii	“The approved test method is ASTM method no. E1367-92 (or the most current EPA approved method) and monitoring for this parameter shall be once per month per well.”	The approved test method is EPA Method 1644 and monitoring for this parameter shall be once per month per well.
Part I Section 2.d.ii	“Monitoring for the parameter shall be performed at least once per year on each fluid blend using the 10-day LC50 sediment toxicity test specified in ASTM E1367-92 (or the most current EPA approved method), and reported on the DMR.”	Monitoring for the parameter shall be performed at least once per year on each fluid using EPA Method 1644 and reported on the DMR.
Part I Section 2.d.iii	“Monitoring for the parameter shall be performed at least once per year on each fluid blend using International Standards Organization (ISO) Method 11734:1995 (or the most current EPA approved method) and results reported on the DMR.”	Monitoring for the parameter shall be performed at least once per year on each fluid using EPA Method 1647 and results reported on the DMR.
Part V.A.2	“The approved sampling and test methods for permit compliance are provided in the final effluent guidelines published at 58FR 12507 on March 4, 1993, as Appendix 2 to subpart A of 40 C.F.R. Part 435.”	The approved sampling and test methods for permit compliance is EPA Method 1619 (Drilling Fluids Toxicity Test).
Part V.A.3	“The approved sampling and test methods for permit compliance are provided in the final effluent guidelines published at 58 FR 12506 on March 4, 1993 as Appendix 1 of subpart A of 40 C.F.R. Part 435.”	The approved sampling and test method for permit compliance is EPA Method 1617 (Static Sheen Test).
Part V.A.6	“The approved test method for permit compliance is identified as ASTM E1367-92 (or most current EPA approved method) entitled, Standard Guide Conducting 10-day Static Sediment Toxicity Test s with Marine	The approved test method for permit compliance is EPA Method 1644 (Sediment Toxicity Test for NAF and SBM) and sediment preparation procedures specified in EPA Method

	and Estuarine Amphipods (or the most current EPA approved method), with <i>Leptocheirus plumulosus</i> as the test organism and sediment preparation procedures specified in Appendix 3 of 40 C.F.R. Part 435, subpart A.”	1646 (Procedure for Mixing Base Fluids with Sediments).
Part V.A.7	“The approved method for permit compliance is identified as International Standards Organization (ISO) 11734:1995 (or the most current EPA approved method) entitled, water quality – Evaluation of the ultimate anaerobic biodegradability of organic compounds in digested sludge – Method by measurement of the biogas production (1995 edition), supplemented with modification in Appendix 4 of 40 C.F.R. part 435, subpart A.”	The approved method for permit compliance is EPA Method 1647 (Determination of the Amount of Non-Aqueous Drilling Fluid (NAF) Base Fluid from Drill Cuttings by a Retort Chamber (Derived from API Recommended Practice 13B–2)).
Part V.A.9.a	“The approved test method for permit compliance is Gas Chromatography/Mass Spectrometry (GC/MS) contained in Appendix 5 of 40 C.F.R. Part 435, subpart A (or most current EPA approved method).”	The approved test method for permit compliance is EPA Method 1655 (Determination of Crude Oil Contamination in Non-Aqueous Drilling Fluids by Gas Chromatography/Mass Spectrometry (GC/MS)).
Part V.A.9.b	“The approved test method for permit compliance is the RPE method in Appendix 6 of 40 C.F.R. Part 435, subpart A, which is applied to drilling fluid removed from drill cuttings. If the operator wished to confirm with results of the RPE method (Appendix 6 of 40 C.F.R. Part 435, subpart A), the operator may use the GC/MS compliance assurance method (Appendix 5 of 40 C.F.R. Part 435, subpart A).”	The approved test method for permit compliance is EPA Method 1670 (Reverse Phase Extraction (RPE) Method for Detection of Oil Contamination in Non-Aqueous Drilling Fluids (NAF)), which is applied to drilling fluid removed from drill cuttings. If the operator wished to confirm with results of the RPE method (EPA Method 1670), the operator may use the GC/MS compliance assurance method (EPA Method 1655).
Part V.A.10	“The approved test method for permit compliance is identified as ASTM E1367-92 (or the most current EPA approved method) entitled, Standard Guide Conducting 10-day Static Sediment Toxicity Test s with Marine and Estuarine Amphipods, with <i>Leptocheirus plumulosus</i> as the test organism and sediment preparation	The approved test method for permit compliance is EPA Method 1644 (Sediment Toxicity Test for NAF and SBM) and sediment preparation procedures specified in EPA Method 1646 (Procedure for Mixing Base Fluids with Sediments).

	procedures specified in Appendix 3 of 40 C.F.R. Part 435, subpart A.”	
Part V.A.14	“Protocol for the Determination of Degradation of Non aqueous Base Fluids in a Marine Closed Bottle Biodegradation Test System: Modified ISO 11734.”	This section should be removed as the procedures are outline in EPA Method 1647 (Protocol for the Determination of Degradation of Non-Aqueous Base Fluids in a Marine Closed Bottle Biodegradation Test System: Modified ISO 11734:1995).

Justification and Supporting Documentation:

The requested language change in the sections noted above ensures that there is standardization in testing methods across the permit. Further, this will reflect industry practices regarding testing terminology and references.

Appendix

Item 1:

Below is a summary of the test results for the barite samples using Method 7471B and the newer methods (7473), (245.7 +3051A).

	Cold vapor AA Method 7471B	Method 7473 Instrument 3000	Method 7473 Instrument 80	Method 245.7 with Method 3051A digestion
Sample	Hg mg/kg	Hg mg/kg	Hg mg/kg	Hg mg/kg
Barite Samples 20151501	0.06		0.05	
Barite control sample with know .62 Mean Hg Value (API Control)	0.53		0.57	
Barite samples 20053089	0.57	0.714		
barite with known long term average value of 2.2 mg/kg (ViVi)	2		1.97	
Barite 20151609	7.5	0.734	0.89	8.01

Review of Method Scope and Application

Region 4 proposed and alternatives	Region 6 current
Analyses for cadmium shall be conducted by EPA Methods 200.7, 200.8 or EPA Method 3050 B followed by 6010 B or 6020A (EPA SW 846), or more recently approved EPA methods, and results shall be expressed in mg/kg (dry weight) of stock barite. Analysis for mercury shall be conducted using EPA method 245.7 or EPA method 7471 A (EPA SW 846), or most recently approved EPA methods, and expressed as mg/kg (dry weight) of stock barite.	Analyses for mercury shall be conducted using EPA Method 245.5, Method 7471 A , or more recently approved methods and the results expressed in mg/kg (dry weight). Analysis for cadmium shall be conducted using EPA methods 200.7, 200.8, or EPA method 3050 B followed by 6010B or 6020, or more recently approved methods and the results expressed as mg/kg (dry weight) of barite.
Method 245.7 - 1.1 Method 245.7 is for determination of mercury (Hg) in filtered and unfiltered water by cold-vapor atomic fluorescence spectrometry (CVAFS). It is applicable to drinking water, surface and ground waters, marine water, and industrial and municipal wastewater. IN 2008	Method 245.5 1.1 This procedure measures total mercury (organic (1) + inorganic) in soils, sediments, bottom deposits and sludge type materials.
EPA METHOD 7471 a WAS REVISED TO EPA METHOD 7471b in 2007 7471B 1.1 This method is a cold-vapor atomic absorption procedure for measuring the following RCRA analyte in soils, sediments, bottom deposits, and sludge-type materials: Analyte CAS Number*	EPA METHOD 7471 a WAS REVISED TO EPA METHOD 7471b in 2007 7471B 1.1 This method is a cold-vapor atomic absorption procedure for measuring the following RCRA analyte in soils, sediments, bottom deposits, and sludge-type materials:

Mercury, total (organic and inorganic) 7439-97-6 * Chemical Abstracts Service Registry Number	Analyte CAS Number* Mercury, total (organic and inorganic) 7439-97-6 * Chemical Abstracts Service Registry Number
EPA method 7473 1.1 This method is for the determination of the following RCRA analyte in solids, aqueous samples, and digested solutions in both the laboratory and field environments: aqueous samples, and digested solutions in both the laboratory and field environments: Analyte CAS No.a Mercury total (organic and 7439-97-6inorganic) Chemical Abstract Service Registry Number	

References:

Method 245.5 - Mercury in Sediment (Manual Cold Vapor Technique)

https://www.bucksci.com/catalogs/EPA%20Method%20-%20245_5%20-%20Mercury%20In%20Sediment%20Manual%20Cold%20Vapor.pdf

1.1 This procedure measures total mercury (organic (1) + inorganic) in soils, sediments, bottom deposits and sludge type materials.

Method 245.7 - Mercury in Water by Cold Vapor Atomic Fluorescence Spectrometry

<https://nepis.epa.gov/Exe/ZyNET.exe/P1008IY8.txt?ZyActionD=ZyDocument&Client=EPA&Index=2000%20Thru%202005&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&UseQField=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A%5CZYFILES%5CINDEX%20DATA%5C00THRU05%5CTXT%5C00000025%5CP1008IY8.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=hpf&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=4>

Method 245.7 is for determination of mercury (Hg) in filtered and unfiltered water by cold-vapor atomic fluorescence spectrometry (CVAFS). **It is applicable to drinking water, surface and ground waters, marine water, and industrial and municipal wastewater.** The method is based on a method developed through a collaboration between EPA's Environmental Monitoring Systems Laboratory, EPA Region 4, and Technology Applications, Inc. (Reference 1), and on results from single-laboratory and interlaboratory validation studies. The method contains procedures for controlling contamination that are based on peer-reviewed, published procedures for the determination of mercury in aqueous samples, ranging from marine waters to effluents (References 2–6).

Method 7471B - Mercury in Solid or Semisolid Waste (Manual Cold-Vapor Technique)

<https://www.epa.gov/sites/production/files/2015-07/documents/epa-7471b.pdf>

“1.1 Method 7471 is approved for measuring total mercury (organic and inorganic) in soils, sediments, bottom deposits, and sludge-type materials. All samples must be subjected to an

appropriate dissolution step prior to analysis. If this dissolution procedure is not sufficient to dissolve a specific matrix type or sample, then this method is not applicable for that matrix.”

Method 7473 - Mercury in Solids and Solutions by Thermal Decomposition, Amalgamation, and Atomic Absorption Spectrophotometry

<https://www.epa.gov/sites/production/files/2015-07/documents/epa-7473.pdf>

“1.1 This method is for the determination of the following RCRA analyte in solids, aqueous samples, and digested solutions in both the laboratory and field environments:

Analyte CAS No.a Mercury total (organic and 7439-97-6 inorganic)
Chemical Abstract Service Registry Number

Integration of thermal decomposition sample preparation and atomic absorption detection reduces the total analysis time of most samples to less than 5 min in either the laboratory or field setting. Total mercury (organic and inorganic) in soils, sediments, bottom deposits, and sludge-type materials as well as in aqueous wastes and ground waters can be determined without sample chemical pretreatment using this method, except as noted. Alternatively, this method can be used for the detection of total mercury from total decomposition sample preparation methods, such as Method 3052, or for detection of extracted or leached mercury compounds or species from methods such as the 3000 series methods (as detailed in Chapter Three).

NOTE: For unique circumstances when mercury could be bound in silicates or other matrices that may not thermally decompose, validation of direct analysis of the solid should be confirmed with total decomposition with an appropriate method (such as Method 3052), followed by analysis with this method.”

Method 3051A - Microwave Assisted Acid Digestion of Sediments, Sludges, Soils, and Oils

<https://www.epa.gov/sites/production/files/2015-12/documents/3051a.pdf>

“1.1 This microwave extraction method is designed to mimic extraction using conventional heating with nitric acid (HNO₃), or alternatively, nitric acid and hydrochloric acid (HCl), according to EPA Method 200.2 and Method 3050. Since this method is not intended to accomplish total decomposition of the sample, the extracted analyte concentrations may not reflect the total content in the sample. This method is applicable to the microwave-assisted acid extraction/dissolution‡ of sediments, sludges, soils, and oils for the following elements:”

Method 3050 B - Acid Digestion of Sediments, Sludges, and Soils

<https://www.epa.gov/sites/production/files/2015-06/documents/epa-3050b.pdf>

“1.1 This method has been written to provide two separate digestion procedures, one for the preparation of sediments, sludges, and soil samples for analysis by flame atomic absorption spectrometry (FLAA) or inductively coupled plasma atomic emission spectrometry (ICP-AES) and one for the preparation of sediments, sludges, and soil samples for analysis of samples by Graphite Furnace AA (GFAA) or inductively coupled plasma mass spectrometry (ICP-MS). The extracts from these two procedures are not interchangeable and should only be used with the analytical

determinations outlined in this section. Samples prepared by this method may be analyzed by ICPAES or GFAA for all the listed metals as long as the detection limits are adequate for the required end-use of the data. Alternative determinative techniques may be used if they are scientifically valid and the QC criteria of the method, including those dealing with interferences, can be achieved. Other elements and matrices may be analyzed by this method if performance is demonstrated for the analytes of interest, in the matrices of interest, at the concentration levels of interest (See Section 8.0). The recommended determinative techniques for each element are listed below:

<u>FLAA/ICP-AES</u>		<u>GFAA/ICP-MS</u>
Aluminum	Magnesium	Arsenic
Antimony	Manganese	Beryllium
Barium	Molybdenum	Cadmium
Beryllium	Nickel	Chromium
Cadmium	Potassium	Cobalt
Calcium	Silver	Iron
Chromium	Sodium	Lead
Cobalt	Thallium	Molybdenum
Copper	Vanadium	Selenium
Iron	Zinc	Thallium
Lead		
Vanadium		

Element		CAS Registry No. ^a
Lead	(Pb)	7439-92-1
*Magnesium	(Mg)	7439-95-4
Manganese	(Mn)	7439-96-5
Mercury	(Hg)	7439-97-6
Molybdenum	(Mo)	7439-98-7
Nickel	(Ni)	7440-02-0
Potassium	(K)	7440-09-7
Selenium	(Se)	7782-49-2
*Silver	(Ag)	7440-22-4
Sodium	(Na)	7440-23-5
Strontium	(Sr)	7440-24-6
Thallium	(Tl)	7440-28-0
*Vanadium	(V)	7440-62-2
Zinc	(Zn)	7440-66-6

Element		CAS Registry No. ^a
*Aluminum	(Al)	7429-90-5
*Antimony	(Sb)	7440-36-0
Arsenic	(As)	7440-38-2
*Barium	(Ba)	7440-39-3
*Beryllium	(Be)	7440-41-7
Boron	(B)	7440-42-8
Cadmium	(Cd)	7440-43-9
Calcium	(Ca)	7440-70-2
*Chromium	(Cr)	7440-47-3
Cobalt	(Co)	7440-48-4
Copper	(Cu)	7440-50-8
*Iron	(Fe)	7439-89-6

Item 2:

Excerpts from “Development Document for Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category” (January 1993, EPA 821-R-93-003, AVAILABLE:

https://www.epa.gov/sites/production/files/2015-06/documents/o_g_offshore_dd_1993.pdf):

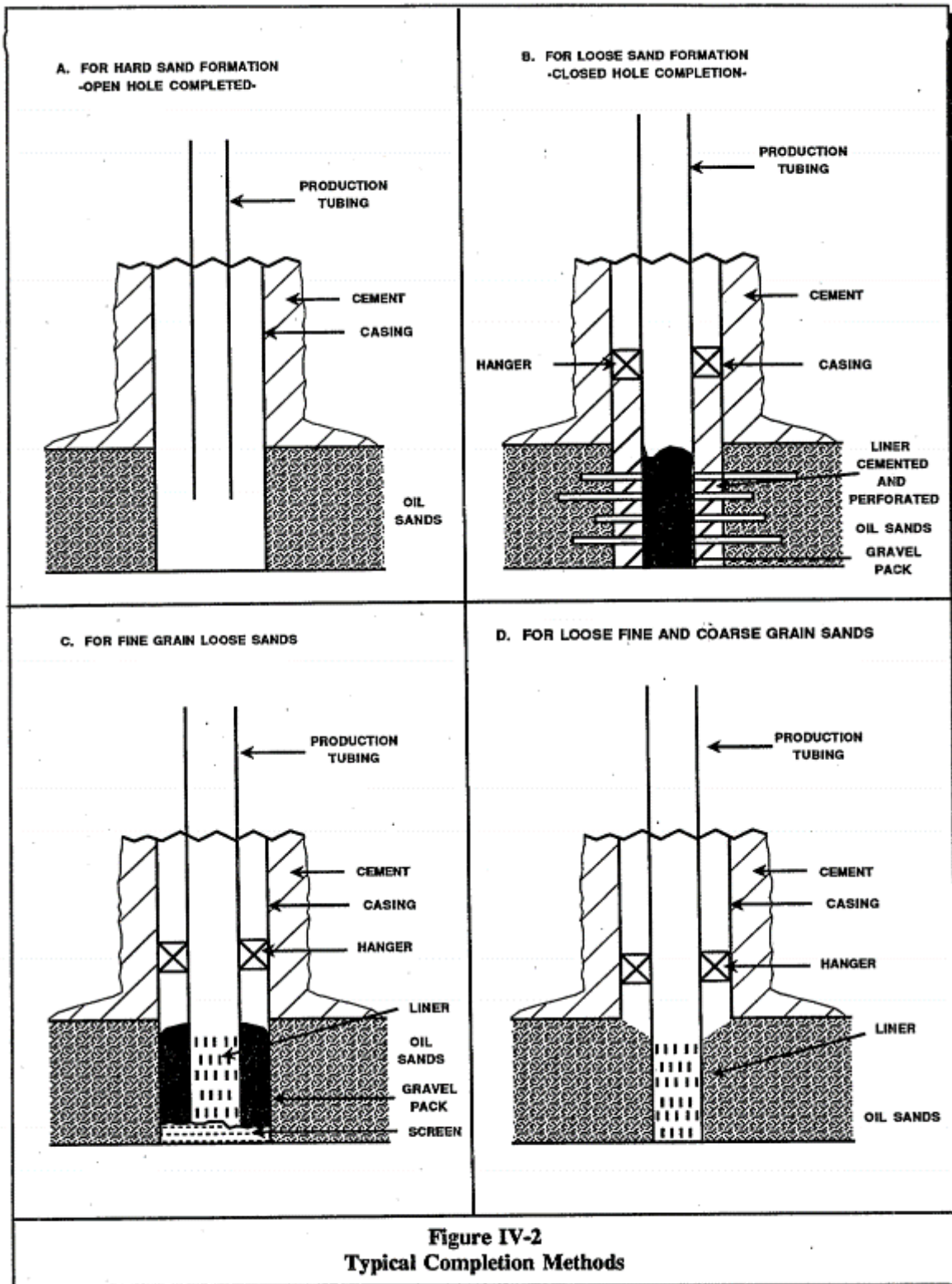
3.2 COMPLETION

Completion operations include the setting and cementing of the production casing, packing the well and installing the production tubing. The completion process installs equipment in the well which allows hydrocarbons to be extracted from the reservoir. Completion methods are determined based on the type of formation, such as hard sand, loose sand, fine grain loose sand, and loose fine and coarse grain sands. Bridging agents are used to prevent fluid loss from the well to the formation.^{6,7}

There are two types of completions, open hole and cased hole. Open hole completions are performed on consolidated formations. Cased hole completions are performed on unconsolidated formations. The majority of completions in the Gulf of Mexico are cased hole.⁸ Figure IV-2 presents schematic diagrams of four common completion methods for different formation characteristics.

The completion process consists of the following steps: wellbore flush, production tubing installation, casing perforation, and wellhead installation. The following paragraphs give a brief description of each of these steps.

The initial wellbore flush consists of a slug of seawater that is injected into the casing. These fluids are considered cleaning or pre-flush fluids and can be circulated and filtered many times to remove solids from the well and minimize the potential for damage to the formation.⁹ When the well has been cleaned, a second completion fluid termed a "weighing fluid" is injected. This fluid maintains sufficient pressure to prevent the formation fluids from migrating into the hole until the well completion is finished.



Production tubing is then installed inside the casing using a packer which is placed at or near the end of the tubing. The packer consists of pipe, gripping elements, and sealing elements made of rubber that keep the tubing in place and expand to form a pressure-tight seal between the production tubing and the well casing.^{3,10} This seals off the annular space and forces the reservoir fluids to flow up the tubing and not into the well annulus.

Packer fluids are completion fluids that are trapped between the casing and the production tubing by the packer. They can provide long-term corrosion protection. Packer fluids are typically mixtures of a polymer viscosifier, a corrosion inhibitor, and a high concentration salt solution.¹¹ Packer fluids remain in place and may be removed during workover operations.¹²

The production tubing must then be perforated to allow the formation fluids to flow into the wellbore. The most common method of cased hole completion is perforation. The casing in the well is perforated to allow the hydrocarbons to flow from the reservoir to the well. Perforation may be accomplished with the use of a special perforating gun (usually lowered into the well by wireline) that fires steel bullets or shaped charges which penetrate the casing and cement. An additional means of perforation is achieved by suspending a small perforated pipe from the bottom of the casing.^{3,10}

The final step in well completion is the installation of the "Christmas tree," a device that controls the flow of hydrocarbons from the well. The Christmas tree may be installed on the platform (a surface completion) or below the waterline on or below the seafloor (a subsea completion). When the valves of the Christmas tree are initially opened, the completion fluids remaining in the tubing are removed and fluid flow from the formation begins.

3.4 WELL TREATMENT

Well treatment is the process of stimulating a producing well to improve oil or gas productivity. There are two basic methods of well treatment, hydraulic fracturing and acid treatment. The specific method is chosen based on the characteristics of the reservoir, such as type of rock and water cut.¹⁰ A well treatment job will enlarge the existing channels within the formation and increase the productivity of the formation. Typically, hydraulic fracturing is performed on sandstone formations,¹⁰ and acid treatment is performed on formations of limestone or dolomite.⁷

Hydraulic fracturing injects fluids into the well under high pressure, approximately 10,000 pounds per square inch. This causes openings in the formation to crack open, increasing their size and creating new openings. The fracturing fluids contain inert materials referred to as "proppants," such as sand, ground walnut shells, aluminum spheres, and glass beads, that remain in the formation to prop the channels open after the fluid and pressure have been removed.^{7,13} Hydraulic fracturing is rarely done in offshore operations because the unconsolidated sandstone formations in the Gulf of Mexico do not require fracturing and the operation requires significant logistical support (i.e., deck space, pumps, mixing equipment, etc.) that is expensive to provide offshore.⁴

Acid stimulation is done by injecting acid solutions into the formation. The acid solution dissolves portions of the formation rock, thus enlarging the openings in the formation. The two most

common types of acid treatment are acid fracturing and matrix acidizing. *Acid fracturing utilizing high pressures* results in additional fracturing of the formation. Matrix acidizing uses low pressures to avoid fracturing the formation. The acid solution must be water soluble, safe to handle, inhibited to minimize damage to the well casing and piping, and inexpensive.⁷

In addition to well treatment using hydraulic fracturing and acidizing, chemical treatment of a well may also be performed. Well treatment with an organic solvent like xylene or toluene will remove paraffin or asphalt blocks from the wellbore. These deposits of solid hydrocarbons occur due to the decrease in temperature and pressure when the liquid hydrocarbons are extracted from the well.¹⁴

3.5 WORKOVER

Workover operations are performed on a well to improve or restore productivity, evaluate the formation, or abandon a well.⁸ Loss of productivity can be the result of worn out equipment, restricted fluid flow due to sand in the well, corrosion, malfunctions of lift valves, etc. Several sources indicated that workover operations include well pulling, stimulation (acidizing and fracturing), washout, reperforating, reconditioning, gravel packing, casing repair, and replacement of subsurface equipment.^{7,15,16} One source indicates that a well will require workover operations every 3-5 years¹⁶ and another indicates that the average well receives treatment or is worked over approximately every 4 years.⁶ The need for workover is related to the percentage of brine in the production fluids. Workover can be performed as often as every 2 years in wells producing greater than 50 percent brine.⁹

The four general classifications of workover operations are pump, wireline, concentric, and conventional.⁸ Workovers can be performed using the original derrick from the drilling platform, a mobile workover rig, or by wireline. The operation is begun by forcing the production fluids back into the formation to prevent them from exiting the well during the operation. Then tools and devices can be attached to the wireline (a spool of strong fine wire) and lowered and pulled from the well to perform the require operations.

4.0 WELL TREATMENT, COMPLETION AND WORKOVER FLUIDS

In the Offshore Guidelines, EPA is controlling pollutants found in well treatment, completion and workover fluids commingled and treated with produced water by limiting oil and grease to 29 mg/l monthly average and a 42 mg/l daily maximum. Separate discharges of these wastes are limited by both the above oil and grease limitations and a prohibition on the discharge of free oil. These limitations represent the appropriate level of control under BAT and NSPS.

The pollutants identified to be present in well treatment, completion and workover fluids are summarized in Tables X-12, X-13, and X-14 for workover, completion and well treatment fluids.

Oil and grease serves as an indicator for toxic pollutants in the well treatment, workover and completion fluids waste stream, including, phenol, naphthalene, ethylbenzene, toluene, and zinc. EPA has determined that it is not technically feasible to control these toxic pollutants specifically, and that the limitations on oil and grease in well treatment, workover, and completion fluids reflect control of these toxic pollutants at the BAT and NSPS levels.

EPA has determined, moreover, that it is not feasible to regulate separately each of the constituents in well treatment, completion and workover fluids because these fluids in most instances become part of the produced water wastestream and take on the same characteristics as produced water. Due to the variation of types of fluids used, the volumes used and the intermittent nature of their use,

VI-7

EPA believes it is impractical to measure and control each parameter. However, because of the similar nature and commingling with produced water, the limitations on oil and grease in the Offshore Guidelines will control levels of certain toxic priority and nonconventional pollutants for the same reason as stated in the previous discussion on produced water.

4.1 POLLUTANTS NOT REGULATED

While the oil and grease and, in certain instances, the no free oil limitations limit the discharges of toxic and nonconventional pollutants found in well treatment, completion and workover fluids, certain other pollutants are not controlled. EPA exercised its discretion not to regulate these pollutants because EPA did not detect them in more than a very few of the samples within the subcategory and does not believe them to be found throughout the offshore subcategory; and the pollutants when found are present in trace amounts not likely to cause toxic effects.

SECTION XIV

COMPLIANCE COST AND POLLUTANT LOADING DETERMINATION— WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS

1.0 INTRODUCTION

This section presents the compliance costs for the final regulatory options for treatment and disposal of well treatment, workover, and completion fluids.

2.0 COMPLIANCE COSTS AND POLLUTANT REMOVAL CALCULATION METHODOLOGY

The compliance costs for the BCT, BAT and NSPS treatment options for well treatment, workover, and completion (TWC) fluids are based on volumes of TWC fluids generated and the size of the production platform where the fluids are being generated. Pollutant removals associated with the treatment options were not calculated because there is insufficient data on the chemical characteristics of well treatment, workover, and completion fluids and the fact that since these fluids vary from well to well, a generalized characterization of TWC fluids would be inadequate.

3.0 WELL TREATMENT, WORKOVER, AND COMPLETION FLUIDS GENERATION RATES

The average volume of workover and completion fluids generated is 300 barrels per well. This volume accounts for a preflush and postflushing of the well and weighting fluid for a 10,000 foot well. According to industry comments and literature, workover and completion fluids are typically reused at least once, so if the same workover or completion is used for two wells, the fluid generated per well is reduced to 150 barrels. The average volume of treatment fluids generated is 250 barrels per well and treatment fluids are typically spent at the end of the job, and thus are not reused. Well workovers or treatment jobs were reported to occur approximately every four years. Well completions are a function of the number of development wells drilled.¹

For the purpose of estimating the volumes of well treatment, workover, and completion fluids generated, EPA projected the occurrences of well treatments, workovers, and completions over a fifteen

year period. Yearly volumes were calculated based on the yearly average of the total volumes generated over the fifteen year period.

4.0 BCT REGULATORY OPTIONS

The BCT limitations for the final rule prohibit the discharge of free oil. Compliance with this limitation is determined by the static sheen test. Because of a lack of sufficient data regarding the levels of conventional pollutants present in both treated and untreated well treatment, workover, and completion fluids, EPA only considered the BCT option as being equal to BPT. There are no costs or non-water quality environmental impacts associated with this BCT limitation.

5.0 BAT AND NSPS OPTIONS CONSIDERED

Well treatment, workover, and completion fluids may either stay in the hole, resurface as a concentrated volume (slug), or surface from the well dispersed with the produced water. Two options were considered for BAT and NSPS control for this waste stream: (1) establish the requirements equal to the current BPT limit of no discharge of free oil (with compliance determined by the static sheen test); or (2) meet the same limitations on oil and grease content as produced water.

In its preferred option for the March 1991 proposal, EPA presented effluent limitations for well treatment, completion, and workover fluids based on requiring zero discharge of any concentrated fluids slug along with a buffer volume preceding and following the fluids slug. Fluids which did not resurface as a distinct slug were proposed to comply with produced water limitations. EPA has since determined that a limitation which requires capturing a buffer volume on either side of a fluids slug is not technologically achievable because it is not always possible and may not be entirely effective. In commenting on the proposal, the industry characterized completion and workover fluid discharges as small volume discharges which occur several times during the workover or completion operations which can last between seven and thirty days. Based on this information, EPA no longer considers the discrete slug and buffer to be a proper characterization of the way workover, completion or treatment fluids resurface from the well. Since the fluids often resurface slowly and over a period of time, and are often commingled with produced water, EPA considers treatment of these fluids commingled with produced water in the produced water treatment system to be the appropriate technology.

The prohibition on the discharge of free oil and cotreatment with produced water requirement are both intended to reduce or eliminate the discharge of toxic pollutants. The method of compliance with

the free oil prohibition is the static sheen test. For the no free oil limitation, EPA determined that there would be no incremental compliance costs. The incremental costs and pollutant removals for option 2 are discussed in Sections XIV.5. Pollutant removals are not calculated for option 2 because of the difficulty in characterizing this wastestream.

6.0 INCREMENTAL COST CALCULATIONS

Option 2 requires well treatment, workover, and completion fluids to meet the oil and grease limitations of produced water based on the technology of cotreating these fluids with the produced water treatment system. Treating these fluids with produced water is considered to incur no, or minimal, additional compliance costs. Costs to properly operate the produced water treatment system and monitor for compliance are accounted for in the compliance cost projections for produced water. However, some facilities may be unable to treat well treatment, workover, and completion fluids with the produced water and would incur compliance costs under this option. The following paragraphs discuss the costing methodology for those facilities.

Some facilities may not be able to commingle TWC fluids with the produced water stream for treatment because of the relative volume of produced water generated and/or the size of the produced water treatment system. In this case, the introduction of the TWC fluids to the produced water treatment system may dramatically affect the separation efficiency of the treatment system resulting in non-compliance with the NPDES permit and subsequent fines. A 1989 industry report stated that facilities with less than ten producing wells would most likely experience produced water treatment system upsets due to commingling of TWC fluids with the produced water stream for treatment. The report stated that facilities with greater than ten wells will have large enough treatment systems to provide sufficient dilution of the TWC fluids such that upsets will not occur. To account for the technical limitations of commingling TWC fluids, EPA developed compliance costs based on the technology of capturing and transporting the wastes to shore for treatment and/or disposal for facilities with fewer than ten well slots. The only platforms with fewer than ten well slots are located in the Gulf of Mexico. In the EPA's production profiles, these facilities are the model platforms Gulf 1a, 1b, 4, and 6. Onshore disposal costs for TWC fluids were developed for the Gulf 1a, 1b, 4, and 6 facilities currently discharging offshore, which is 67 percent since 37 percent of all structures in the Gulf are currently piping produced water to shore for treatment.¹

6.1 VOLUMES GENERATED FROM EXISTING STRUCTURES

To calculate the volumes of well treatment and workover fluids generated from existing facilities (completions are considered new sources), EPA assumed that a well treatment or workover job would occur every four years. EPA also estimated the average volume generated from either a well treatment or workover job as being 200 barrels a job (This is the arithmetic average of typical volume generated from a well treatment, which is 250 barrels, and from a workover, which is 150 barrels). EPA developed a yearly well treatment/workover volume by dividing the average volume generated by four. The total volumes of well treatment and workover fluids generated were calculated by multiplying the average yearly volume by the total number of wells. Table XIV-1 presents the volumes of well treatment and workover fluids generated from the existing Gulf 1a, 1b, 4, and 6 model platforms.

TABLE XIV-1

TOTAL BAT WORKOVER AND TREATMENT VOLUME GENERATION ESTIMATES

Structure Type:	Total Structures Discharging Offshore	Number of Wells per Structure	Total Number of Producing Wells	Volume of Workover/Treatment Fluids Generated (barrels per year)	Onshore ReInjection Costs (\$/yr)
Oil Facilities:					
Gulf 1a	89.55	2	89.55	4,477.5	53,730
Gulf 1b	13.23	2	13.23	661.5	7,938
Gulf 4	27.72	8	110.88	5,544	66,528
Gulf 6	11.97	12	71.82	3,591	43,092
Oil and Gas:					
Gulf 1a	139.86	2	139.86	6,993	83,916
Gulf 1b	61.74	2	61.74	3,087	37,044
Gulf 4	75.6	8	302.4	15,120	181,440
Gulf 6	80.01	12	480.06	24,003	288,036
Gas:					
Gulf 1a	332.01	2	332.01	16,600.5	199,206
Gulf 1b	170.1	2	170.1	8,505	102,060
Gulf 4	110.88	8	443.52	22,176	266,112
Gulf 6	100.8	12	604.8	30,240	362,880
Total:	1,213.47		2,819.97	140,998.5	1,691,982

6.2 VOLUMES GENERATED FROM NEW STRUCTURES

The constrained scenario drilling profiles were used to calculate the volumes of completion fluids generated from new sources. EPA identified the projected number of new wells drilled associated with the Gulf 1b, 4, and 6 model platforms. EPA determined that 1754 wells would be drilled under the constrained scenario from the Gulf 1b, 4, and 6 model platforms over the 15 year period following

promulgation of this rule. For a more detailed discussion on the constrained scenario refer to the *Economic Impact Analysis* for this rule. A yearly average of wells drilled was calculated to determine the yearly number of completions and the yearly volume of completion fluids generated. The average number of wells drilled per year from a Gulf 1b, 4, and 6 model platform is 115.

The number of well treatment and workover jobs for new source wells was determined based on the fact that a well treatment or workover is done every four years and that 115 new wells are drilled per year. In the first four years of the fifteen year period, no treatment or completion jobs are done but in the fifth year 115 treatment or completion jobs are performed and in the subsequent years more treatment or workover jobs are performed as the population of existing wells increases. The average well treatment/workover fluid volume was used to determine the total treatment/workover fluid volumes generated from new sources.

Table XIV-2 presents the volumes of well treatment, completion, and workover fluids generated from new source Gulf 1b, 4, and 6 model platforms.

TABLE XIV-2

**NSPS WORKOVER AND COMPLETION SCHEDULE, VOLUME ESTIMATES,
DISPOSAL COSTS**

Year	Number of Wells Drilled Per Year	Number of Workover/Treatment Jobs Done Per Year	Number of Completion Jobs Done Per Year	Volumes of Workover/Treatment Fluids Generated (barrels per year)	Volumes of Completion Fluids Generated (barrels per year)	Workover/Treatment Injection Costs (\$ per year)	Completion Injection Costs (\$ per year)	Total Onshore Injection Costs (\$ per year)
1	115	0	115	0	17,250	0	207,000	207,000
2	115	0	115	0	17,250	0	207,000	207,000
3	115	0	115	0	17,250	0	207,000	207,000
4	115	0	115	0	17,250	0	207,000	207,000
5	115	115	115	23,000	17,250	276,000	207,000	483,000
6	115	115	115	23,000	17,250	276,000	207,000	483,000
7	115	115	115	23,000	17,250	276,000	207,000	483,000
8	115	115	115	23,000	17,250	276,000	207,000	483,000
9	115	230	115	46,000	17,250	552,000	207,000	759,000
10	115	230	115	46,000	17,250	552,000	207,000	759,000
11	115	230	115	46,000	17,250	552,000	207,000	759,000
12	115	230	115	46,000	17,250	552,000	207,000	759,000
13	115	345	115	69,000	17,250	828,000	207,000	1,035,000
14	115	345	115	69,000	17,250	828,000	207,000	1,035,000
15	115	345	115	69,000	17,250	828,000	207,000	1,035,000
Totals:	1,725	2,415	1,725	483,000	258,750	\$ 796,000	3,105,000	8,901,000
Average workover/treatment costs over 15 year period:						386,400 dollars per year		

6.3 STORAGE COSTS

EPA assumed that there would be no cost for the containment of the spent fluids prior to transporting them to shore for disposal. This assumption is based on the fact that during well treatment, workover, or completion, storage tanks currently exist on the platform or on tending workboats for fluid storage and separation. (To ensure compliance with the current BPT limitations prohibiting discharge of free oil, operators must maintain the capability to capture fluids which, if discharged, would cause a sheen on the receiving waters.) EPA believes that these tanks would provide adequate storage between capturing the fluids as they come out of the well and the time of transporting the fluids to shore.

6.4 TRANSPORTATION COSTS

EPA also did not assign any incremental costs to the transportation of the fluids to shore. Based on comments from industry, EPA determined that the volumes would be small and the regularly scheduled supply boats would have adequate space to transport the containers of spent fluids. As discussed in the above paragraph, EPA determined that the platforms would have adequate space for storage of the spent fluids for the periods when the supply boats are not scheduled for the platform or when offloading to the supply boats is infeasible due to weather conditions.

6.5 ONSHORE DISPOSAL COSTS

EPA determined the most common method of onshore treatment of spent fluids to be injection into underground formations at a centralized treatment facility. The disposal costs are estimated to be \$12 per barrel. This cost includes the costs of transporting the fluids from an inland port transfer station to the disposal facility, solids removal if necessary, and reinjection.

6.6 BAT AND NSPS VOLUMES AND DISPOSAL COSTS

Table XIV-1 presents the BAT workover and treatment volume generation estimates and onshore disposal costs. Volume estimates and disposal costs for completion fluids are not included in the BAT costs because completion fluids are considered wastes from new sources and hence are only assigned to the NSPS costs.

Table XIV-2 presents the yearly NSPS workover, treatment, and completion generation volumes and disposal costs for the fifteen years following promulgation of this rule. Table XIV-2 also presents the average yearly workover and treatment fluid disposal costs for the 15 year period.

7.0 REFERENCES

1. Memorandum from Allison Wiedeman, Project Officer to Marv Rubin, Branch Chief. "Supplementary Information to the 1991 Rulemaking on Treatment/ Workover/Completion Fluids," December 10, 1992.

Item 3:

The most sensitive Zn detection limit can be as low as 0.5 ug/L (0.5 ppb):

TABLE IB—LIST OF APPROVED INORGANIC TEST PROCEDURES—Continued

Parameter, units and method	Reference (method number or page)				
	EPA 1, 35	Standard Methods [Edition(s)]	ASTM	USGS 2	Other
75. Zinc —Total, ⁴ mg/L; Digestion ⁴ followed by:					
AA direct aspiration ³⁶	289.1	3111 B or C [18th, 19th]	D1691–95(A or B)	I–3900–85	974.27, ³ p. 37 ⁹
AA furnace	289.2.				
ICP/AES ³⁶	200.7 ⁵	3120 B [18th, 19th, 20th] ...		I–4471–97 ⁵⁰ .	
DCP, ³⁶ or			D4190–94		Note 34.
Colorimetric (Dithizone) or		3500–Zn E [18th, 19th].			
(Zincon)		3500–Zn B [20th] and 3500–Zn F [18th, 19th].			Note 33.

Item 4 :

Mineral Makeup of Seawater In order of most to least:

ELEMENT	MOLECULAR WEIGHT	PPM IN SEAWATER	MOLAR CONCENTRATION
Chloride	35.4	18980	0.536158
Sodium	23	10561	0.459174
Magnesium	24.3	1272	0.052346
Sulfur	32	884	0.027625
Calcium	40	400	0.01
Potassium	39.1	380	0.009719
Bromine	79.9	65	0.000814
Carbon(inorganic)	12	28	0.002333
Strontium	87.6	13	0.000148
Boron	10.8	4.6	0.000426
Silicon	28.1	4	0.000142
Carbon (organic)	12	3	0.00025
Aluminum	27	1.9	0.00007
Fluorine	19	1.4	0.000074

N as nitrate	14	0.7	0.00005
Nitrogen (organic)	14	0.2	0.000014
Rubidium	85	0.2	0.0000024
Lithium	6.9	0.1	0.000015
P as Phosphate	31	0.1	0.0000032
Copper	63.5	0.09	0.0000014
Barium	137	0.05	0.00000037
Iodine	126.9	0.05	0.00000039
N as nitrite	14	0.05	0.0000036
N as ammonia	14	0.05	0.0000036
Arsenic	74.9	0.024	0.00000032
Iron	55.8	0.02	0.00000036
P as organic	31	0.016	0.00000052
Zinc	65.4	0.014	0.00000021
Manganese	54.9	0.01	0.00000018
Lead	207.2	0.005	0.000000024
Selenium	79	0.004	0.000000051
Tin	118.7	0.003	0.000000025
Cesium	132.9	0.002	0.000000015
Molybdenum	95.9	0.002	0.000000021
Uranium	238	0.0016	0.0000000067
Gallium	69.7	0.0005	0.0000000072
Nickel	58.7	0.0005	0.0000000085
Thorium	232	0.0005	0.0000000022
Cerium	140	0.0004	0.0000000029
Vanadium	50.9	0.0003	0.0000000059
Lanthanum	139.9	0.0003	0.0000000022
Yttrium	88.9	0.0003	0.0000000034
Mercury	200.6	0.0003	0.0000000015

Silver	107.9	0.0003	0.0000000028
Bismuth	209	0.0002	0.00000000096
Cobalt	58.9	0.0001	0.0000000017
Gold	197	0.000008	0.00000000004

0.014 ppm = 14 ppb

Source: <https://web.stanford.edu/group/Urchin/mineral.html>